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Intermodel Comparison Between Switch 2.0 and GE MAPS: Evaluating a New Tool for Integrated Modeling of Electric Vehicles and High-Renewable Power Systems

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ABSTRACT

Electric Vehicles (EVs) could help increase energy security and reduce greenhouse gas emissions by using electricity produced from clean, domestic sources instead of imported oil. This benefit could be enhanced if EVs are adopted in high-renewable power systems and are charged at the times when renewable power is most abundant, producing a win-win arrangement in which EVs enable greater adoption of renewable power in the grid. With its unique geography and current fossil fuel based energy infrastructure combined with its aggressive renewable energy goals, Hawaii forms an ideal site for large-scale adoption of EVs in the future.

This report presents results from the Hawaii Natural Energy Institute (HNEI) at the University of Hawaii's (UH's) project on the "Effect of Electric Vehicles on Power System Expansion and Operation," in partnership with the Electric Vehicle Transportation Center at the University of Central Florida. This project's overall focus is on studying the synergies between well-timed EV charging and the design and operation of high-renewable power systems. This work requires high-quality, validated models of electric power systems. To support this effort, UH investigators configured the Switch power system model similarly to the GE Multi-Area Production Simulation (GE MAPS) model, as it was used by GE Energy Consulting for HNEI's recent Hawaii Renewable Portfolio Standards Study. GE MAPS is a widely respected and frequently used production-cost model for power systems. When configured with similar input data, researchers found that the two models agree very closely on how high-renewable power systems would be operated, including hourly production from individual power plants, annual curtailment rates for renewable energy facilities, and total annual production from different power sources. The models agree on 97 percent of the variation in curtailment and 65–100 percent of the variation in generator usage across 17 diverse scenarios of renewable energy and transmission deployment on Oahu and Maui. This work gave investigators confidence to continue using Switch to investigate interactions and synergies between EV charging and high-renewable power systems.

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CONTENTS

1 INTRODUCTION

This report presents an inter-model comparison between the Switch and GE Energy Consulting, (GE) Multi Area Production Simulation (MAPS) power system models. This work was conducted as part of the project on the "Effect of Electric Vehicles on Power System Expansion and Operation" under a sub award to the Hawaii Natural Energy Institute, University of Hawaii at Manoa (UH), from the Electric Vehicle Transportation Center (EVTC) at the Florida Solar Energy Center, University of Central Florida. The EVTC is a University Transportation Center funded by the Research and Innovative Technology Administration of the US Department of Transportation. The EVTC is a research and education center whose projects prepare the US transportation system for the influx of electric vehicles (EVs) into a sustainable transportation network and include investigation of the opportunity these vehicles present to enhance electric grid modernization efforts.

The objective of the "Effect of Electric Vehicles on Power System Expansion and Operation" project was to examine the effects of EVs on electric power system design and operation. The work included expanding the Switch model (previously created by the author) to better model interactions and improve coordination between EV charging and power production in advanced, high-renewable power systems.

In order to investigate the synergies between well-timed EV charging and the design and operation of high-renewable power systems, a high-quality, validated model of electric power systems is required. In this report, we present the results of a comparison between Switch and an existing, widely used power system model, GE MAPS. GE MAPS performs hourly economic dispatch of generation to meet hourly load plus operating reserves. It is used to quantify energy production, variable cost, wind and solar power curtailment, impact of EV charging load and schedule, emissions, etc. for a pre-specified scenario of asset construction. Switch is a capacity expansion model, designed to optimize the construction of power systems with large shares of renewable power, storage and demand response. Switch also provides capabilities to study coordination between EV charging (or other forms of dynamic demand response) and the design and operation of the power system. These capabilities make it possible to study how improved coordination of EV timing could reduce the cost of charging while simultaneously facilitating adoption and integration of renewable power (e.g., by preferentially charging at times when renewable power would otherwise be discarded). However, Switch is not yet widely recognized by power system planners. So in this part of the project, we compared Switch to GE MAPS. Specifically, we tested whether Switch would produce similar results to GE MAPS when studying 18 scenarios of renewable energy adoption for Oahu and Maui, as recently reported in the *Hawaii Renewable Portfolio Standards Study* (RPS Study) [1].

We focused on the RPS Study because it was a recent study that investigated different pathways to integrate high-renewable power generation, by modeling future scenarios for Hawaii using industry-standard software. GE MAPS is widely used for renewable integration studies in Hawaii and elsewhere [e.g., 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12], and has been calibrated against system operations in Oahu and Maui [13, 14].

Switch is primarily designed as a capacity expansion model, which means that it selects which assets to build in the power system in order to minimize costs while meeting policy objectives. Embedded within this are unit-commitment and dispatch algorithms that decide which plants to turn on each hour and how much power to provide from those plants. GE MAPS, on the other hand, is a production-cost model, which means that it focuses on unit-commitment and dispatch, using pre-specified portfolios of power system assets. Consequently, this intermodel comparison focuses only on a subset of Switch's capabilities. However, this is a critical subset, which encompasses most of the important interactions between renewable power, thermal power plants and electricity demand.

Switch normally uses mixed-integer optimization methods for unit commitment and dispatch. GE MAPS uses linear optimization methods for unit commitment, with heuristic rules to enforce integer decision variables. For the Hawaii work, GE MAPS was also specially configured to match the Hawaiian Electric Companies' heuristic unit commitment rules. Consequently, significant effort was invested in determining the rules and data that were input into GE MAPS, in order to configure Switch with similar logic and data. The RPS Study report included a great deal of useful information, and GE was generous in providing additional data and answers to inquiries. However the goal of the RPS study was to evaluate different pathways of renewable integration in Hawaii, rather than to document modeling parameters or inputs. Consequently some operational details were inferred from the figures and results presented in the RPS Study, and in some cases assumptions were made that may have differed from ones that GE MAPS used. It's important to note that Hawaii modeling and data is continually being updated, and the RPS Study report focused on results rather than the modeling process or detail, as is the focus of this report.

Despite uncertainties about the assumptions and data used in the RPS Study, we found that Switch produced results that were very close to GE MAPS. This allowed us to proceed with confidence on the other portions of the project on the Effect of Electric Vehicles on Power System Expansion and Operation, focusing on synergies between EV charging and the design and operation of a high-renewable power system. It should be noted that this comparison was conducted in a small region with minimal transmission constraints; results cannot necessarily be extrapolated to larger power systems with more complex transmission networks.

This report is organized into two main sections. Section 2 gives a brief overview of Switch and reports the data, assumptions and background references that were used to configure Switch for the intermodel comparison. This section is primarily aimed at people with an interest in the technical details of power system modeling, especially in Hawaii. Section 3 is much briefer, and presents the results of this intermodel comparison. These primarily show data from GE MAPS that were presented in the RPS Study and compare them to results from Switch. These are followed by a brief conclusion (Section 4).

2 SWITCH MODEL CONFIGURATION

2.1 Switch Power System Planning Model

Switch is a next-generation capacity expansion model, designed to optimize the construction of power systems with large shares of renewable power, storage and demand response. Switch was released as open-source software in 2008 [15, 16], and has subsequently been used for a number of long-term studies of renewable energy adoption [17, 18, 19, 20, 21, 22]. Switch standardizes and automates the process of selecting generation and transmission assets for high-renewable power systems. This, in turn, enables a new class of studies of how renewable energy and climate policies would affect the cost of power production, or how new technologies such as storage or dynamic demand-response could help with achieving climate and energy goals.

A new version of Switch, 2.0 has recently been completed [23, 24]. Switch 2.0 uses a highly flexible, modular software framework, which allows users to select among different formulations for each part of the power system. The modules provided with Switch 2.0 also include much more operational detail than Switch 1.0 and most other capacity expansion models, including unit commitment, part-load power plant efficiencies and spinning reserve targets. With this new flexibility and codebase, Switch 2.0 can be readily configured to match the formulation of most standard capacity expansion or production cost models.

Switch has primarily been designed for capacity expansion modeling – choosing the least-cost portfolio of assets to build in order to provide adequate power over a multi-decade period, while meeting climate and clean-energy goals. However, with the new unit-commitment and reserve capabilities in version 2.0, it is also possible to provide predefined asset portfolios and use Switch as a high-resolution production-cost model. Since GE MAPS is a production cost model without capacity expansion features, we used Switch in production-cost mode for this intermodel comparison.

For this intermodel comparison, we configured Switch 2.0 with similar assumptions and data to GE MAPS, as discussed below. We used standard Switch modules for time sampling; financial calculations; generator construction, commitment and dispatch; transmission construction and operation (in flowgate mode); operating reserve balancing areas; and fuel cost calculations. We also used a module for Kalaeloa unit commitment that is shared with other Hawaii models. And we added two custom modules to implement heuristic unit commitment rules similar to the Hawaiian Electric rules applied in GE MAPS and to report results for this intermodel comparison.

The generic version of Switch 2.0 is available from ref. 24. The data and code used for this intermodel comparison are available from ref. 25. To conduct the analyses reported in section 3 for Oahu and Maui, we divided the year into 12 months, solved the individual models, and then aggregated the results. This resulted in 204 production cost models to solve. These were solved in about 10 minutes via parallel processing on the UH high performance computing system. Total compute time for the 17 scenarios on a single four-core desktop computer would be about four hours. This is longer than the run-time for GE MAPS, which was reported to be under 30 minutes [26].

2.2 RPS Study Scenarios

The RPS Study considered 18 scenarios of renewable resource adoption on the islands of Oahu and Maui [1, p. 14]. These were characterized by varying amounts of wind and solar generating capacity and various combinations of inter-island transmission cables. New transmission options included a “grid-tie cable” to enable bidirectional sharing of power between the Oahu and Maui power systems allowing the two island grids to operate as a single power system, and a “gen-tie” cable to carry power from wind farms on Lanai to the Oahu power system, without connecting to Lanai’s local power system. Scenario 1 in the RPS Study considered the current power systems without significant changes. Scenario 2 included system upgrades including improvements to the flexibility of existing generators, but no additional renewable power beyond Scenario 1. Scenarios 3–18 included the same system upgrades as Scenario 2, plus various amounts of new renewable power and transmission.

Since we were most interested in comparing GE MAPS and Switch’s performance in high-renewable scenarios, we configured Switch to simulate scenarios 2–18 for this intermodel comparison.

Table 1 shows the amount of wind, distributed solar photovoltaic (PV) and utility-scale solar PV included in scenarios 2–18 of the RPS Study, as well as the amount of gen-tie wind and grid-tie transmission capacity added in each scenario. Switch was configured according to these values for the intermodel comparison. Note that scenarios 2–9 focused on changes only to the Oahu power system, with the Maui power system unchanged from its current state and no gen-tie wind or grid-tie transmission. Scenarios 10–18 added new renewable and transmission capacity to both islands.

Table 1. *Renewable and transmission capacity in scenarios 2–18 (MW)*

Scenario	Oahu Wind	Oahu Central PV	Oahu Dist. PV	Maui Wind	Maui Central PV	Maui Dist. PV	Gen-Tie Wind	Grid-Tie Cable
2	100	11	220	72	0	40	0	0
3	100	200	260	72	0	40	0	0
4	200	200	260	72	0	40	0	0
5	300	200	260	72	0	40	0	0
6	100	300	360	72	0	40	0	0
7	200	300	360	72	0	40	0	0
8	200	400	460	72	0	40	0	0
9	200	300	560	72	0	40	0	0
10	100	200	260	72	0	78	200	0
11	100	200	260	272	0	78	0	200
12	100	200	260	272	100	78	200	200
13	100	300	360	72	0	78	200	0
14	100	300	360	272	0	78	0	200
15	100	300	360	272	100	78	200	200
16	200	400	460	72	0	78	200	0
17	200	400	460	272	0	78	0	200
18	200	400	460	272	100	78	200	200

2.3 Thermal Generator Properties

Table 7 of the RPS Study report [1, p. 59] showed most of the details needed in Switch to model the operation of individual thermal power plants. For each plant, these include:

- retirement status
- mode indicators (baseload, cycling, peaking or firm renewables),
- fuel indicators (coal, LSFO, diesel, biodiesel, waste),minimum loads for cycling and baseload plants,
- heat rate (efficiency) curves and variable operation and maintenance (O&M) costs for most HECO- and MECO-owned plants,
- forced outage rates,
- minimum up- and down-time constraints, and
- energy required to startup plants.

In most cases, we used these details directly in Switch. We also gathered or inferred other information needed to conduct the Switch modeling, as discussed in the remainder of section 2.3.

2.3.1 Operating Cost for Third-Party Thermal Plants

The RPS Study report did not specify the operating costs that it used for third-party thermal power plants – H-Power, Honua, AES and Kalaeloa. However, GE reported separately that they modeled the waste-to-energy plants (H-Power and Honua) as having a take-or-pay contract following a schedule [27], so we treated them the same in Switch.

In the Hawaii Solar Integration Study [7, p. 46], GE reported that they modeled operation of AES and Kalaeloa the same way as they modeled HECO-owned fossil-powered plants, i.e., used representative heat-rate (efficiency) curves provided by HECO, with standard costs for fuels. So for these plants, we used the heat rate segments reported in the Hawaii Solar Integration Study [7, p. 191], fitted to the quadratic form that GE used for the RPS Study. Variable O&M costs were not reported for either of these plants in either study. For AES, we used a variable O&M rate of $2 per MWh [28, p. 18]. For Kalaeloa, we set the variable O&M to $8.59/MWh, which resulted in the same full-load operating cost as reported in Figure 30 of the RPS Study [1].

2.3.2 Fixed Operating Schedules for Power Plants

The RPS Study divides thermal power plants into four categories: baseload, firm renewable (“firm RE”), cycling, and peaking [1, Table 7, p. 59]. Generally, GE MAPS committed baseload and firm RE plants at all times that they were not out for maintenance, but committed cycling and peaking plants as needed, based on the day-ahead renewable energy forecast (cycling and peaking plants) or real-time conditions (peaking plants) [1, pp. 17 and 45; 29, slide 31; 30, 31, 27]. Firm RE plants also had fixed dispatch schedules [27]. “Commitment” means the decision about whether to have a plant online at a particular time, as opposed to “dispatch,” which refers to the amount of power to produce from a committed plant.

There were two exceptions to this general pattern: the Kalaeloa plant on Oahu and the Maalaea combined cycle plants on Maui were all identified as “baseload” plants in the RPS Study. Both of these plants are dual-train combined cycles that can operate in single train (1x GT + ½ ST) or dual train (2x GT + 1 ST). As a result, we determined that GE MAPS was able to turn some of their units on and off like cycling plants (this is discussed further below). Consequently, in the

Switch modeling, we allowed the flexible units to be committed as needed based on the day-ahead forecast (like cycling plants), but we treated them as baseload generators in all other respects (i.e., allocating up and down reserve targets and reporting production).

Note: GE studied a sensitivity case in which they removed the must-run requirement for baseload plants and used a commitment queue instead, as discussed in Section 5.2.2 of the RPS Study [1, pp. 45–47]. However, for their main model runs, they retained the must-run requirements [26].

We configured Switch to follow the same commitment and dispatch schedules as GE MAPS used for their main model runs. The subsections below discuss the commitment and dispatch schedules for some individual power plants in GE MAPS. Any plants not discussed below followed the general pattern discussed above.

2.3.2.1 Oahu Firm RE Plants

The RPS Study did not report how the firm renewable energy plants on Oahu (H-Power and Honua) were scheduled. However, GE reported separately [27] that they modeled H-Power and Honua as following a fixed schedule at maximum output other than during outages. They also provided details on the hourly production from Oahu plants in scenarios 2 and 16 [32], from which we inferred the dates of full and partial outages for H-Power (Honua had no outages).

2.3.2.2 Kalaeloa Combined Cycle Plant

GE reported separately [27] that "There is a cogen requirement that forces Kalaeloa to operate in either single train (KAL1) or dual train (KAL2) as must-run (unless both units are on forced outage). There is also a scheduled weekly maintenance cycle for each GT [gas turbine] that takes Kal1 out of service on Friday evening into Saturday morning, and Kal2 out of service from Saturday evening to Sunday morning." The Hawaii Solar Integration Study [7, p. 46] identified these wash times as 9 pm Friday or Saturday to 9 am Saturday or Sunday. The clock used in Switch starts 1 hour earlier than GE MAPS (first hour of the day is 0 in Switch, 1 in GE MAPS), so this corresponds to the 8 pm hour through the 8 am hour, inclusive in Switch. Inspection of Figures 8 and 9 of the RPS Study [1, pp. 22–23] also indicated that GE MAPS was able to decommit the second Kalaeloa unit when not needed.

Consequently, in the Switch modeling, we configured Kalaeloa 1 to be committed at all times except from the 8 pm hour on Friday through the 9 am hour Saturday, and configured Kalaeloa 2 to be committed at all times when Kalaeloa 1 was out of service, unless Kalaeloa 2 was also scheduled to be out of service. We also scheduled Kalaeloa 2 to be out of service from 8:00 pm Saturday through 8:59 am Sunday. At all other times, there were no restrictions on whether Kalaeloa 2 was committed or not (i.e., we treated it like a cycling unit).

By inspection of Figures 8 and 9 of the RPS Study [1, pp. 22–23], we determined that Kalaeloa produced at least 75 MW at all times (even though each unit's minimum load was 65 MW). We assumed this reflected the cogen requirement, so we configured Switch to dispatch at least 75 MW from the Kalaeloa plant whenever it was not on maintenance outage.

2.3.2.3 Maui Peaking and Cycling Units

An earlier validation report for the Maui version of GE MAPS, "Maui Electrical System Simulation Model Validation" [from 2008, 14, p. 5] indicated that Maalaea units 4–9 (a mix of cycling and peaking generators) were not available from 10 pm to 7 am. This restriction was not mentioned in the RPS Study report, but we configured Switch to enforce this constraint.

2.3.2.4 Maui Combined Cycle Units

The Maui validation report for GE MAPS said that the Maalaea CC1 plant (consisting of M14, M15 and M16) operated in dual-train combined-cycle mode (using all three units) at all times, and that Maalaea CC2 (M17, M18, M19) operated in dual-train mode from 6 am to 10 pm and single-train mode (turning off M17 or M19) from 10 pm to 6 am [14, p. 4]. The RPS Study report said that scenarios 2–18 included "cycling of Maalaea CC" as a departure from current practice [1, p. 13]. It was unclear from these sources what commitment restrictions were placed on the Maalaea combined cycle units (M14–M19) in GE MAPS. We configured Switch to commit Maalaea CC1 (M14–16) at all times and allow unrestricted cycling of Maalaea CC2 (M17–19).

2.3.3 Operating Modes for Combined-Cycle Plants

Kalaeloa power plant. The Kalaeloa combined cycle power plant consists of two combustion turbines, one steam turbine powered by waste heat from the combustion turbines. GE reported that they modeled these as three units: Kalaeloa 1 and 2 each consisted of one combustion turbine and half of the steam turbine, and Kalaeloa 3 represented additional peaking capacity available if operating in dual-train combined cycle mode [7, p. 46; 13 p. 3; 27; 26]. They also reported that Kalaeloa 3 could operate in quick-start mode if Kalaeloa 1 and 2 were producing at their rated power level. We configured Switch to match this logic, i.e., only allowing Kalaeloa 3 to produce power if Kalaeloa 1 and 2 were at maximum output.

In the Hawaii Solar Integration Study, GE reported that "Kalaeloa operates in single train [mode] (67-90 MW) for at least five hours before entering dual train mode (134-180 MW)" [7, p. 46]. Due to time constraints, we did not include this requirement when configuring Switch for the intermodel comparison. However, this is not likely to have a large effect on the results, since at least one Kalaeloa unit is committed at all times, making it possible to commit the second one at any time.

Maalaea combined cycle plants. We modeled each of the Maalaea combined-cycle power plants as two single-train combined cycle generators (a total of four units). Each of these plants consists of two combustion turbines and one steam turbine. GE reported properties for each of these plants on an aggregate basis in Table 7 of the RPS Study report [1, p. 59], identifying the two aggregated plants as Maalaea CC1 and CC2. We assume these correspond to units 14/15/16 and 17/18/19, respectively. However, in Table 11 of the RPS Study [1, p. 64] GE reported maintenance outages for four units: M1415, M1516, M1718 and M1819. As noted in the previous paragraph, they also modeled the Kalaeloa combined-cycle plant as two single-train units. Based on this information, we believed it was most likely that GE MAPS modeled the Maalaea plants as four single-train units, but reported them as CC1 and CC2 in Table 7 of the RPS Study report and M1415, M1516, M1718 and M1819 in Table 11 of the RPS Study. So we deleted the information for CC1 and CC2 in Table 7 of the RPS Study report and replaced it with profiles for four single-train combined-cycle units: Maalaea 1415, Maalaea 1516, Maalaea 1718 and Maalaea 1819. The properties reported for CC1 and CC2 were adjusted so that each pair of units would perform the same as the original aggregated plant, if both units were dispatched in tandem. To achieve this, we divided the minimum load and baseline fuel consumption in half (coef A in Table 7 of the RPS Study), kept the fuel consumption per MWh unchanged (coef B), and doubled the quadratic fuel consumption term (coef C).

2.3.4 Minimum Load and Part-Load Heat Rates for Peaking Plants

GE reported separately that they modeled peaking plants with no minimum load (meaning they can operate anywhere between 0 and 100% of their rated load), and with a single incremental heat rate for all operating levels because they are expected to run rarely, and usually near full load [27]. We configured Switch to match these assumptions.

2.3.5 Startup Fuel

Table 7 of the RPS Study report [1, p. 59] showed that the Kahe 1–6 and Waiau 7–8 generating units require much more energy to startup when cold than when hot. We configured Switch to use the "cold" startup energy because in this study these baseload units are only restarted after multi-week maintenance outages, if ever.

2.3.6 Generator Maintenance and Forced Outages

The RPS Study did not show the times when forced outages occurred in the GE MAPS modeling, and GE reported separately that their maintenance outages differed from HECO's schedules shown in Table 11 of the RPS Study [1], in order to avoid interfering with normal operation and reserve margins each week [26].

We inferred the dates of full outages for most thermal power plants in Oahu by inspection of hourly production data for Oahu plants in Scenarios 2 and 16 which GE provided separately [32]. We assumed that baseload plants were on maintenance or forced outage on all days when they produced zero power. We assumed cycling plants were out of service when they produced no power but lower-priority peaking plants produced some power. We also noted that there were no zero-power days for wind and solar projects on Oahu or Maui, from which we inferred that these plants had no maintenance or forced outages.

We were not able to identify forced outages for peaking plants or Maui plants by this technique. For these plants, we applied the maintenance schedules shown in Table 11 of the RPS Study [1] and then applied random 3-day outages until each plant's forced outage rate was 2.5% higher than the level shown in Table 7 of the RPS Study [1]. The 2.5% adder was used because we found that outage rates for the Oahu baseload and cycling plants were an average of 2.5% higher than the sum of the maintenance schedules shown in Table 11 and the forced outage rates shown in Table 7 of the RPS Study [1].

It is important to note that this technique was also unable to identify partial outages at power plants (e.g., times when they could only run at 35% or 50% of normal output). By inspection of the hourly production data [32] we noted that there were a number of times when partial outages occurred; however we were not able to identify these systematically in the time available for this study, so we omitted them from the Switch modeling. This is likely to introduce a bias toward baseload production rather than cycling or peaking production in all scenarios. It may also introduce a bias toward Oahu baseload over Maui baseload in the gen-tie scenarios (simply because there is more Oahu baseload capacity).

2.4 Transmission Network

GE MAPS models transmission using an AC power flow, with DC variations with each commitment and dispatch decision [33, p. 31; 26]. Switch is normally run with a flowgate-based transmission model, or it can be run with (experimental) security-constrained AC power flow. Since no network information was reported for the RPS Study, we ran Switch in flowgate mode, with no congestion or losses within each island, and finite transmission capacity between islands (in grid-tie scenarios). This formulation should provide accurate results when there are two zones with strong internal transmission networks, connected by a single AC or DC line. We assumed that all power flows over the DC line incurred losses of 3.8%. This loss rate was estimated by comparing total production reported by GE in the grid-tie-only scenarios (11, 14 and 17) to total production in scenario 2 [1, Tables 8 and 9]. We divided the extra production in the grid-tie scenarios (presumed to be due to grid-tie losses) by the total line flow reported for these cases [1, Table 2] to get an average loss rate of 3.8%.

Also see section 2.7 for a discussion of transmission losses for gen-tie wind, which we assumed were 5% at all times.

2.5 Fuel Costs

We configured Switch with the fuel costs reported for Oahu and Maui in Table 6 of the RPS Study [1, p. 58].

2.6 Capital Costs

We configured Switch to use the capital costs reported for new generating and transmission assets in Table 3 of the RPS Study [1, p. 28]. We applied a fixed charge rate of 10% to all these costs, to match the rate used for Figures 13 and 14 of the RPS Study [1, p. 29–30]. This corresponds to 30-year financing at an interest rate of 9.31%. GE reported that they did not include capital costs for existing thermal power plants [1, p. 30], so we also omitted these costs in Switch. GE reported that they treated costs for lower turndown capability on baseload units or fuel switching to diesel as sunk costs [26]; we used the same approach with Switch.

2.7 Hourly Loads and Renewable Power Production

Data on hourly loads, hourly renewable resource potentials, and day-ahead renewable resource forecasts are essential inputs to renewable planning models. For this project, we used several time series of conditions that could occur during all the hours of 2020, which were provided by GE [34]:

- hourly production for each renewable energy project in each scenario
- day-ahead forecasts of hourly renewable power production in each scenario
- hourly electricity loads for Oahu and Maui

GE synthesized these time series based on hourly conditions during a historical reference year. We did not obtain information on which reference year was used or how these datasets were synthesized. For Hawaii modeling, Switch is usually run with datasets derived from historical loads, meteorological observations and gridded weather models [35, 36, 37]. However, for this intermodel comparison we used the datasets provided by GE, in order to remain as consistent as possible with the GE MAPS modeling.

Transmission losses for gen-tie wind. GE noted that the gen-tie wind experienced losses due to transmission [1, p. 23], but did not specify how large those losses were, or whether the production data they provided [34] was before or after losses. Several factors led us to the conclusion that ref. 34 reported availability of gen-tie wind on a net basis, after losses, but Table 9 and Figure 4 of the RPS Study were based on gross production and availability before losses:

- For three of the gen-tie wind scenarios (10, 12 and 15), we found that the Oahu wind production reported in Table 9 of the RPS Study [1, p. 60] exceeded the total Oahu wind reported to be available in ref. 20.
- Total production in Table 9 rose by about 3.5% of gen-tie wind production in the scenarios where power came from gen-tie wind instead of offshore wind (e.g., 3 vs. 10 or 8 vs. 16). We presume this was due to losses on the gen-tie line.
- The curtailment rates that GE reported in Figure 4 of the RPS Study [1, p. 20] could only be reproduced from the availability and production data [34 and 1, Table 9] if the available power for gen-tie wind in ref. 34 was increased by 5 percent.
- Hourly wind production data provided by GE late in this study [32] showed values for gen-tie wind that were exactly 5% higher than the available resource reported in ref. 34. The hourly values in ref. 32 were also consistent with the annual values shown in Table 9 of the RPS Study [1, p. 60].

We concluded that gen-tie wind experienced losses of 5% due to transmission, and that GE reported production on a gross basis (before losses) in Table 9 and Figure 4 of the RPS Study. So for the Switch modeling, we raised the gen-tie wind availability from ref. 34 by 5% to estimate gross wind availability. We then added losses of 5% within Switch (getting net availability equal to ref. 34), and then reported the production on a gross basis (3.5% higher than ref. 34) in order to report results on the same terms as the RPS Study.

2.8 Spinning Reserve Targets and Allocation

Different regions have different reserve allocation rules. This is one area where it is relatively common to tailor Switch to the rules in effect in a particular region. For this project, we configured Switch to match the rules used by GE MAPS. These include a plant-specific down-reserve allocation and a pooled up-reserve requirement.

Power systems must keep extra generating capacity committed (turned on) at all times in order to compensate for unforeseeable variations in operating conditions. These reserves can be divided into two main “product” categories: contingency reserves, which can compensate for rare events such as loss of a large generator or load; and regulating or operating reserves, which compensate for routine events such as misforecast of loads or renewable power. In addition, reserves can be divided into two main operating modes: spinning reserves, which are in sync with the grid and able to respond to events immediately; and non-spinning reserves, which require time to be brought online. For Hawaiian power systems, spinning reserves are particularly important, since there is no time to bring extra capacity online when an event occurs. In the RPS Study report [1], GE focused almost exclusively on spinning reserves, and we use the same focus in this report.

For the RPS Study, GE MAPS was configured to provide both contingency and regulating reserves in an upward direction, which we call "up reserves." These were kept online to cover sudden loss of a power plant or incoming transmission line, or short-term misforecast of renewable power production. GE MAPS was also configured to provide contingency reserves in a downward direction, which we call "down reserves." These were kept online to compensate for loss-of-load events. Switch was configured to provide the same categories of spinning reserves for this intermodel comparison. The subsections below provide more details on how both models were configured to provide reserves, which are an important driver of generator unit commitment and dispatch. These sections focus separately on up reserves and down reserves, since different strategies were used for each.

2.8.1 Up Reserves

2.8.1.1 Contingency up reserve target

Switch normally sets the region-wide target for upward contingency reserves dynamically, based on the largest generating unit currently committed. However, for the RPS Study, GE pre-calculated contingency targets for Maui and Oahu, since the requirements were relatively static. GE provided us with hourly values for the contingency up target for each power system [34], and we used the same values in Switch.

2.8.1.2 Regulating up reserve target

As part of the Hawaii Solar Integration Study [7], GE developed a technique for estimating the "worst-case" (99.9th percentile), hour-ahead forecast error for power production from a fleet of wind farms and solar arrays. This is a measure of the extra regulating reserves that must be kept online in case the renewable power production drops unexpectedly before additional generating capacity can be turned on. For the RPS Study, GE used this technique to calculate the regulating up reserves required in each hour, in each of the 18 renewable deployment scenarios (1, see Figures 39 and 40). GE provided us with these time series along with the hourly production and day-ahead forecast data discussed in section 2.7 [34].

In the grid-tie scenarios, we configured Switch to divide the regulating reserve target between the two power systems proportional to their hourly load levels. It is likely that GE used a different method to divide this target between Oahu and Maui. However, we were not able to find any documentation of this, so we used the above-mentioned approach. Differences in this area may explain some of the disagreement between Switch and GE MAPS about operating strategies, discussed in section 3.1.

We also noted that GE reduced the regulating reserve target for Maui (or Maui+Oahu) by up to 9.6 MW at all times. We assume this represents provision of part of the regulating reserves from non-spinning, fast-start generators that could be turned on as renewable resources drop or loads rise. We used the same formula when configuring Switch.

2.8.1.3 Interaction between regulating and contingency targets

On Oahu, GE modeled the regulating reserves as a separate target in addition to the contingency reserve target in all scenarios. However, on Maui, in non-grid-tie scenarios (1–9, 10, 13 and 16), the contingency and regulation targets overlap, reflecting local practice. In these cases, the total spinning reserve target is set equal to the maximum of the regulating reserve requirement or the contingency reserve requirement. We configured Switch to use the same reserve targets as GE.

2.8.1.4 Allocating up reserve targets to individual plants

Once the reserve targets are set for each power system, commitment and dispatch of individual power plants must be scheduled to ensure that enough reserves are available at all times. Individual plants can provide spinning up reserves when they are operating (committed), but not producing their maximum output, so that production can be raised on short notice. This "headroom" is each plant's contribution to the system reserve target. A key job of system operating models is to decide how much reserves will be provided from each plant in order to meet the target, i.e., allocating the overall target among individual plants.

It is not clear from the RPS Study report which power plants were designated to provide up reserves. The report says only, "All of the HECO baseload units are modeled to provide a portion of the [up] contingency reserves" [1, p. 61]. Table 7 of the RPS Study [1, p. 59] indicates that the HECO baseload units consist only of Kahe 1–6 and Waiau 7–8. However, for the Switch modeling work, we assumed several additional plants were able to provide up-reserves. These were AES and Kalaeloa (third-party baseload plants) and Waiau 5–6 (HECO-owned cycling plants). We assumed AES and Kalaeloa were included because provision of up-reserves from Kalaeloa was discussed elsewhere in the study [1, pp. 45–46], and because they were designated as able to provide down-reserves [38]. We assumed the cycling plants were able to provide up-reserves based on inspection of Figures 8 & 9 of the RPS Study [1, pp. 22–23].

We also assumed that all plants designated as Baseload or Cycling in Table 7 of the RPS Study [1, p. 59] provided up reserves on Maui. This was nearly the same as indicated in an earlier validation report for GE MAPS [14, p. 5], which said that Maalaea 4–13 and Maalaea CC1 and CC2 (units 14–19) could provide up reserves; the only difference is that we excluded Maalaea units 4 and 6, which were listed as Peaking units in Table 7 of the RPS Study. We excluded these units for two reasons: (a) GE reported separately that "peaking plants were assumed to provide supplemental replacement reserves only" (i.e., bulk power to free up other plants, but not spinning reserves) [31]; and (b) all peaking units (including these) were listed in Table 7 as having minimum loads of 0 MW; consequently, if they were allowed to provide up reserves, they could be "committed" at a 0 MW load and provide up reserves at no cost, which would be unrealistic.

GE reported [38] that GE MAPS optimized production levels and up-reserve provision for all online plants to minimize production cost while respecting the overall reserve target. This is standard practice for economic dispatch software, and is the also the approach normally used by Switch, so we used the same approach in the intermodel comparison.

For the intermodel comparison, we assumed the inter-island grid-tie cable could transfer power at any time to allow unloading other plants, but could not directly provide spinning up reserves.

Despite our best efforts, it is possible that Switch was configured to provide up reserves from a different set of plants (or the grid-tie cable) than GE MAPS, which could contribute to differences in the models' results.

2.8.2 Down Reserves

2.8.2.1 Contingency down reserve target

Down reserves are provided by power plants that are producing power above their minimum stable or permitted level, and are able to reduce production on short notice. Like up reserves, down reserves can be divided into a regulating portion and a contingency portion. Power systems use regulating down reserves to compensate for routine reductions in the need for power (e.g., underforecast of renewable production or overforecast of loads). Contingency down reserves are used for unexpected loss-of-load events, such as a major trip in the transmission or distribution network. For the RPS Study, GE modeled only the contingency portion of down reserves, and we followed the same approach with Switch.

The RPS Study report [1, p. 61] stated that the overall down reserve target for Oahu was set equal to 10% of load in each hour. The RPS Study did not state whether a down reserve target was set in Maui; we found that providing down reserves in Maui increased curtailment above the level reported by GE MAPS, so we did not provide them there.

The RPS Study also stated that the Oahu down reserve target was served partly by utility-scale wind and solar plants, and partly by conventional thermal plants, using the following formula [1, p. 42]:

$$\text{Ratio of Down Reserves from W\&S} = \frac{\text{Wind \& Solar Capacity}}{\text{Wind \& Solar Capacity} + \text{Thermal Capacity}}$$

GE reported separately that the formula is recalculated hourly, and is based on the committed capacity of thermal plants and nameplate rating of utility-scale wind and solar plants [38]; we used that approach for Switch.

We assumed the formula only included the thermal plants that could provide down-reserves (discussed in the next subsection).

The Hawaii Solar Integration Study reported an additional assumption that “the solar and wind plants can contribute to down-reserves only when their output is above 20% of their rated capacity” [7, p. 145]. GE reported separately that the same assumption was used in the RPS Study, and that it was applied per-plant [38]; we used the same approach for Switch.

This gives the following formulas for the active renewable and thermal capacity in hour *h*:

$$[\text{Wind \& Solar Capacity}]_h = \sum_{p \in R_h} [\text{Nameplate Rating}]_p$$

$$[\text{Thermal Capacity}]_h = \sum_{p \in T_h} [\text{Nameplate Rating}]_p$$

where,

$$R_h = \left\{ p \in [\text{Wind \& Solar Plants}]\text{: } \frac{[\text{Available Power}]_{p,h}}{[\text{Nameplate Rating}]_p} \geq 0.2 \right\}$$

$$T_h = \left\{ p \in [\text{Thermal Plants}]\text{: committed}\left(p,h\right) = \text{True} \right\}.$$

Then we used the following, more-specific equations to set the shares of the down-reserve target to be served by utility-scale renewable and thermal plants during each hour *h*:

$$[\text{Ratio of Down Reserves from W\&S}]_h = \frac{[\text{Wind \& Solar Capacity}]_h}{[\text{Wind \& Solar Capacity}]_h + [\text{Thermal Capacity}]_h}$$

$$[\text{Ratio of Down Reserves from Thermal}]_h = 1 - [\text{Ratio of Down Reserves from W\&S}]_h.$$

We then allocated the thermal portion of down-reserves among the individual thermal plants using a process discussed in the next subsection. For the wind and solar plants, we assumed that the 20% rule combined with their low operating cost would ensure that they always produced enough power to satisfy their portion of the down reserve target. Consequently, we did not directly enforce the wind and solar portion of the down-reserve target.

2.8.2.2 Allocating Down Reserve Targets to Individual Plants

For Oahu, the RPS Study states that "All of the baseload HECO units and utility-scale wind and solar generating were modeled to provide down reserves" [1, p. 61]. GE reported separately [29, slide 36; 38] that they assumed that AES and Kalaeloa provided down reserves in addition to all the HECO power plants identified as "Baseload" in the RPS Study [1, table 7]. We followed this approach with Switch.

GE reported separately that "the [down] reserve requirement is set for the thermal units, and then there is a tiered price approach to allocate it evenly" [38]. It appears that a supply-curve type of approach was used to allocate down reserve targets to individual plants, instead of optimizing that decision during the economic dispatch stage. We were not able to obtain or infer the details of this tiered approach in the time available for this study, so we configured Switch to allocate down-reserves in direct proportion to each plant's committed capacity.

It is highly possible that one or both of these assumptions differ from those used in GE MAPS, which could contribute to differences in commitment, dispatch and curtailment between the two models.

2.8.2.3 Effect of Grid-Tie Cable on Down Reserve Targets and Allocation

We assumed that the down reserve target was maintained separately on each island, even when the grid-tie cable was present, i.e., that each island maintained down reserves equal to 10% of its separate load. We also assumed that target was allocated proportionally among the online, down-reserve-capable plants on each island (as identified in section 2.8.2.2). It is possible that GE MAPS used different assumptions, e.g., pooling the down reserve target between islands, and allocating it proportionately to all plants on both islands. We tested that arrangement as well, but did not find it made a significant difference in the annual generation profile.

2.9 Generator Unit Commitment

"Unit commitment" refers to the process of selecting which power plants will be online during a particular time period. This is different from "dispatch," which is the decision about how much power to produce from each committed plant.

Hawaiian Electric uses a priority queue to specify the order in which thermal power plants will be committed. GE MAPS was configured to perform a linearized optimization of unit commitment, subject to this ordering, with additional heuristics to ensure integer constraints are satisfied (i.e., units must be fully committed or not at all) [26, 30]. GE MAPS used two rounds of unit commitment, one based on the day-ahead forecast, and one at real-time, using real-time conditions. All available plants were scheduled in the day-ahead unit commitment, but then peaking plants could be turned on or off as needed in real time [31].

Switch 2.0 normally optimizes unit commitment directly without using a pre-specified commitment order. This is similar to standard unit-commitment models in the literature [39, 40, 41, 42]. For this intermodel comparison, we developed a custom module that forced Switch to follow unit commitment rules similar to those used in the RPS Study instead. Below, we report the assumptions we made about the order of plants in the commitment queues, and the rules that were followed to determine when enough capacity has been committed or to respect minimum up- and down-time limits for power plants, important areas when configuring Switch. We note that these assumptions appear reasonable, but may differ significantly from the approach GE MAPS took, which could produce different results.

2.9.1 Commitment Priority

2.9.1.1 Oahu Power Plants

We prioritized commitment of the Oahu power plants as follows:

1. Firm RE plants and baseload plants except Kalaeloa 2 and 3 (i.e., H-Power, Honua, Kahe 1–6, Waiau 7–8, Kalaeloa 1) were committed at all times they were available.
2. Cycling plants, were committed in order by full-load operating cost (Kalaeloa 2 & 3, then Waiau 5, then Waiau 6).
3. Peaking and biodiesel plants in order by full-load heat rate, but with Schofield moved to end of queue based on information from GE [30].

2.9.1.2 Maui Power Plants

The Maui validation report stated that “The general commitment order was obtained from MECO as: K3, K4, M14/15/16 [CC1], M17/18 [CC2], K1, K2, M10, M19, M11, M12, M13, M8, M9, M4, M6, M1-3, X1, X2, M5, M7” [14, p. 5]. We assumed that GE MAPS followed this sequence for the RPS Study, but with two new internal combustion engines added to the end of the list, and we used the same sequence for Switch.

2.9.1.3 Grid-Tie Scenarios

In grid tie scenarios, the model must prioritize between plants on both Maui and Oahu. We assumed that the two islands’ plants were prioritized as follows:

1. All firm RE and baseload plants except Kalaeloa 2 & 3 (always committed)
2. Oahu cycling plants and Kalaeloa 2 & 3
3. Maui Maalaea 10 through Maalaea 7 from the list in section 2.9.1.2 (mixed cycling and peaking). We placed these later in the ordering than Oahu cycling plants because GE MAPS used them much less intensively than the Oahu cycling plants in the grid-tie scenarios (11–12, 14–15, 17–18) [1, Table 9, p. 60].

4. Oahu peaking plants

The two-island commitment order we used in Switch is shown in Table 2. For scenarios without a grid tie, we used the same order, but considered only the plants on each island.

Table 2. *Commitment order for Oahu and Maui power plants used in Switch for intermodel comparison*

Order	Unit	Order	Unit
1	H-Power (firm RE)	22	Maalaea 11 (cycling)
2	Honua (firm RE)	23	Maalaea 12 (cycling)
3	AES (baseload)	24	Maalaea 13 (cycling)
4	Kalaeloa 1 (baseload)	25	Maalaea 8 (cycling)
5	Kahe 5 (baseload)	26	Maalaea 9 (cycling)
6	Kahe 3 (baseload)	27	Maalaea 4 (peaking)
7	Kahe 4 (baseload)	28	Maalaea 6 (peaking)
8	Kahe 2 (baseload)	29	Maalaea 1 (peaking)
9	Kahe 6 (baseload)	30	Maalaea 2 (peaking)
10	Kahe 1 (baseload)	31	Maalaea 3 (peaking)
11	Waiau 7 (baseload)	32	Maalaea X1 (peaking)
12	Waiau 8 (baseload)	33	Maalaea X2 (peaking)
13	Maalaea CC1415 (baseload)	34	Maalaea 5 (cycling)
14	Maalaea CC1516 (baseload)	35	Maalaea 7 (cycling)
15	Maalaea CC1718 (cycled baseload)	36	New ICE 1 (peaking)
16	Maalaea CC1819 (cycled baseload)	37	New ICE 2 (peaking)
17	Kalaeloa 2 (cycled baseload)	38	Airport DSG (peaking)
18	Kalaeloa 3 (on if Kal 1 & 2 are)	39	CIP CT (peaking)
19	Waiau 5 (cycling)	40	Waiau 9 (peaking)
20	Waiau 6 (cycling)	41	Waiau 10 (peaking)
21	Maalaea 10 (cycling)	42	Schofield (peaking)

2.9.2 Commitment Process

2.9.2.1 Overview

Switch is normally configured to make commitment decisions automatically, in a way that minimizes operating cost while respecting reserve requirements and plant operating rules. However, for the intermodel comparison, we configured Switch to commit plants according to the priority lists discussed in section 2.9.1, in order to more closely match HECO operations simulated in GE MAPS.

Although selecting plants from a queue to meet the energy and reserve targets appears simple at first, it is actually fairly complicated. As the decision maker steps through the commitment queue, the main challenge is determining whether the plants that have already been committed can be dispatched in such a way that they simultaneously meet the requirements for energy, up reserves and down reserves, and minimum up-time and down-time constraints. If not, additional capacity must be committed.

GE used an iterative process to commit plants to meet the power system’s energy and reserve targets, and all power plants were committed based on day-ahead conditions, and then commitment for peaking plants was readjusted based on real-time conditions [29, slide 31; 31, 38].

We configured Switch with a custom commitment algorithm that followed these broad guidelines. Specifically, our algorithm does the following, once for day-ahead commitment, and then again for real-time commitment:

1. Commit units from the appropriate queue until enough capacity is scheduled to meet the total demand for power plus up reserves. This calculation is done on a balancing-area-wide basis (individual islands if there was no grid tie, otherwise both islands together).
2. Commit additional up-reserve-eligible units if needed, until the system has enough up reserve capacity to meet the up-reserve requirement. Up reserve capacity was defined as the maximum production possible with currently committed up-reserve-eligible units, minus the minimum load and down-reserve targets for those units (i.e., the maximum up and down range for all units currently online). GE reported separately that they used the same method [26].

In this algorithm, Steps 1 and 2 work together to ensure that the system has enough energy and up reserves at all times, while taking account of down reserve targets that may impinge on up reserve capacity. Step 1 ensures that the system has enough capacity committed to meet the total requirement for energy and up reserves. Step 2 ensures that the plants that have been committed have enough maneuvering room to provide the required up reserves. Together, these ensure that the system can be dispatched to provide enough power each hour, and also has a band of dedicated up reserves on top of that that is large enough to satisfy the reserve target.

Note that we do not know whether GE MAPS' commitment process was similar to this. For example, we do not know whether MAPS performed its commitment on a multi-island basis or per-island, or the details of how MAPS ensured that the power system could simultaneously meet power and up- and down-reserve requirements.

The following subsection describes these in more detail. The code and data to perform these steps are also available from ref. 25.

2.9.2.2 Commitment Algorithm

The unit commitment algorithm used in Switch for the intermodel comparison consisted of a main workflow and several supporting subroutines. These are each described below. The main process was run once during model initialization to select a commitment schedule for all units during all time steps. Then, during the main optimization phase, unit commitment was constrained to match this schedule.

Note that normally Switch would optimize unit commitment directly; these scheduling rules were added to Switch to mimic HECO and MECO's queue-based approach, as modeled in GE MAPS.

Main commitment process

1. Commit all plants that have a must-run requirement.
2. Perform day-ahead unit commitment for each balancing area. This performs the "commit plants" subroutine (discussed below) for all thermal plants, using the day-ahead renewable energy forecast. This produces a commitment plan for all plants for the next

day. The commitment plan for cycling and baseload plants is locked in at this point, but commitment for peaking generators will be adjusted later.

3. Perform real-time unit commitment:

    a. “Commit” all wind and solar facilities. This adds their real-time output to the subsequent unit commitment calculations.

    b. Reduce commitment for all peaking plants to the minimum allowed level (generally zero). This prepares them for recommitment based on real-time conditions. (Peaking plants are listed in Table 2 of this report and Table 7 of the RPS Study [1].)

    c. Perform real-time unit commitment. This performs the “commit plants” subroutine (discussed below) for only peaking thermal plants, using the real-time renewable energy production. This chooses the right commitment level for peaking plants based on real-time conditions.

“Commit plants” subroutine:

This subroutine contains most of the logic for unit commitment. It is called for a particular balancing area (one island if there is no grid-tie cable, otherwise both islands together). It can optionally be instructed to use a day-ahead forecast of renewable power production. It completes the following steps:

```
# choose commitment queue (ordered list of generating units whose commitment should be
# adjusted upward if needed):

if day-ahead:

    commitment queue is all plants in current balancing area, sorted as shown in Table 2

else:

    commitment queue is all peaking plants in current balancing area, sorted as shown in Table 2

# meet energy and reserve requirements for whole balancing area:

Perform “allocate down reserves” subroutine (below).

For each unit in the commitment queue:

    If this unit requires special commitment:

        Do special commitment and return to top of the loop.

    For each time step:

        If the total capacity currently committed for this time step (including, optionally, the day-ahead
        renewable forecast) is insufficient to meet the energy and up reserve target:

            Commit the current unit.

        Otherwise, if the current generating unit is eligible to provide up reserves and the system
        currently has insufficient up reserve capacity (see section 2.9.2.1):

            Commit the current unit.

    Perform “fix commit schedule” subroutine for current generating unit. This commits the plant if
    necessary in any time step to ensure that the minimum up- or down-time rules are never violated.

    If the current generating unit provides down reserves, perform the “allocate down reserves” routine to
    update all down reserve targets.
```

“Allocate down reserves” subroutine

This subroutine selects a down-reserve target for each down-reserve-eligible thermal generating unit. This is done primarily by choosing a “down reserve fraction,” which is the percentage of each unit’s rated capacity to allocate for down reserves. The same down reserve fraction is applied to all eligible plants. The down reserve quota for each unit is set equal to the lesser of [down reserve fraction times committed capacity] or [committed capacity minus minimum load]. The down reserve fraction is raised until enough down reserves are available (or until the supply from committed plants is exhausted; this typically only happens in the early stages of unit commitment, before all plants are committed).

“Fix commit schedule” subroutine

This subroutine steps through all time steps and commits the plant if necessary to ensure that the minimum up- or down-time rules are never violated. It attempts to fix violations of the minimum up-time rule by extending the commitment schedule later, but if that is not possible, it extends the schedule earlier instead. It fixes violations of the minimum-down-time rule by extending up-time through the brief down-time window (rather than extending down-time). It is possible that GE MAPS uses a much different approach to address these issues.

“Perform special commitment” subroutine

This routine provides specialized commitment for individual generating units that follow unusual rules. In our final configuration, this only applied to the Kalaeloa duct burner (Kalaeloa 3). This routine committed Kalaeloa 3 if and only if Kalaeloa 1 and 2 were already currently committed for the same time step (see section 2.3.2.2).

Notes

The Maui commitment queue (section 2.9.1.2) mixes cycling and peaking units. That is not a problem for this commitment algorithm. This algorithm makes a day-ahead commitment plan following the units’ ordering in the commitment queue (e.g., it may decide not to commit a cycling plant if higher-priority peaking plants provide sufficient capacity). This plan is binding for the cycling plants, but the commitment of the peaking plants is then readjusted based on real-time conditions.

When using this algorithm, Switch did not commit additional units specifically to meet the down reserve requirement; we assumed that by the end of the normal commitment process, enough down-reserve-eligible units were always committed to meet the down reserve target (10% of load, prorated between renewable and thermal capacity; see section 2.8.2).

2.10 Generator Dispatch

For this intermodel comparison, Switch used its standard dispatch logic. Switch is a mixed-integer linear program, which automatically dispatches power plants to minimize cost while satisfying the balancing area’s requirements for power and up reserves, and respecting constraints on the operation of individual plants (e.g., down-reserve quotas). GE MAPS also uses a linear program to solve this problem, so we would expect the same results in this area.

3 RESULTS

We used Switch to repeat several of the analyses that GE conducted as part of the RPS Study. Here we compare a number of the key findings between the two models. Code to run Switch and perform the comparisons is available in ref. 25.

3.1 Annual Power Production from Each Source

Figures 1 and 2 below show the annual power production from each major type of generator, in each of the 17 scenarios that were modeled in the RPS Study, as determined by GE MAPS and Switch. Different energy sources are stacked in each column, and MAPS and Switch results are paired for each scenario. The agreement is generally excellent, within 0.5% of total power production for all categories except for baseload production in scenarios 11, 14 and 17, which differ by 1–2%.

Looking closely at Figure 2, we see several patterns in the differences between GE MAPS and Switch for scenarios 10–18:

- In the independent-grid scenarios (2–9, 10, 13, 16), Switch uses 23–72 GWh more of baseload generation on Oahu than MAPS, and correspondingly less Oahu cycling and peaking generation. This equates to 0.3–0.8% of total production. In these scenarios, Switch uses slightly more Maui peaking generation and slightly less Maui baseload generation than MAPS (7–8 GWh, corresponding to 0.1% of total production).
- In the scenarios with a grid-tie cable but no gen-tie wind (11, 14, 17), Switch uses 120-160 GWh more baseload generation on Oahu than MAPS (1.4–1.9% of total production). It also uses slightly more Maui peaking generation. These are matched by roughly equal decreases in baseload generation on Maui and cycling and peaking generation on Oahu.
- The pattern in the scenarios with gen-tie wind and a grid-tie cable (12, 15, 18) is similar to the grid-tie-only scenarios (more Oahu baseload and Maui peaking, less of other thermal plants), but less pronounced. In these scenarios, Switch also curtails more Oahu wind than GE MAPS and accepts more Maui wind and solar, with a net decrease in renewable production of 0–35 GWh, 0.0–0.4% of total production.

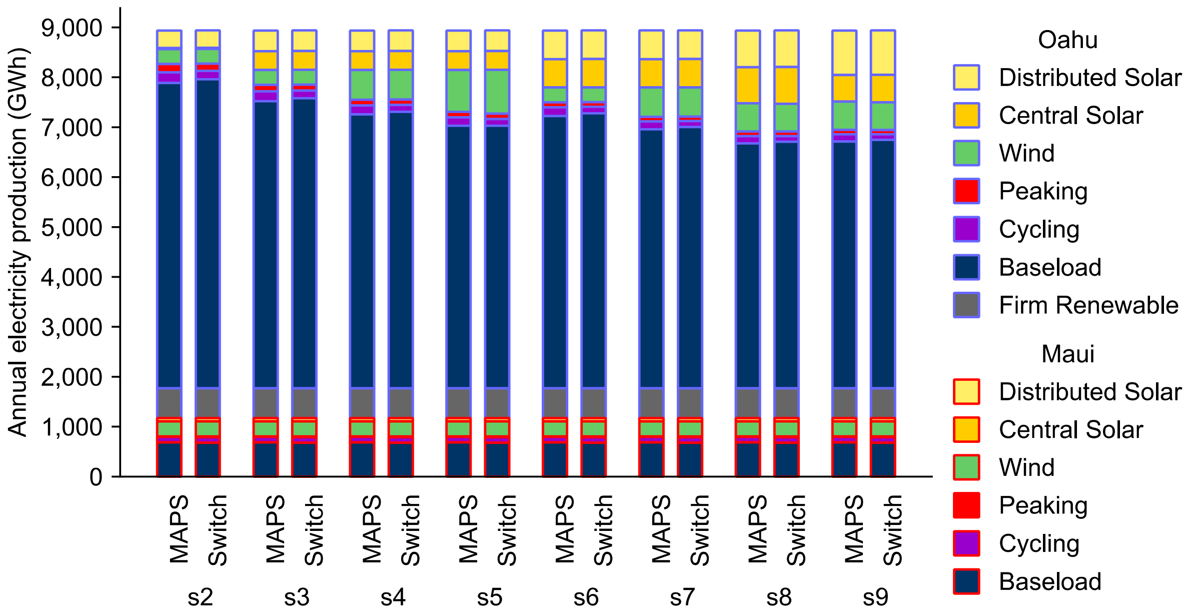

Figure 1. *Annual production from each source in scenarios 2–9, as calculated by GE MAPS and Switch (paired columns for each scenario). Upper, blue-bordered rectangles show Oahu generators; lower, red-bordered rectangles show Maui generators*

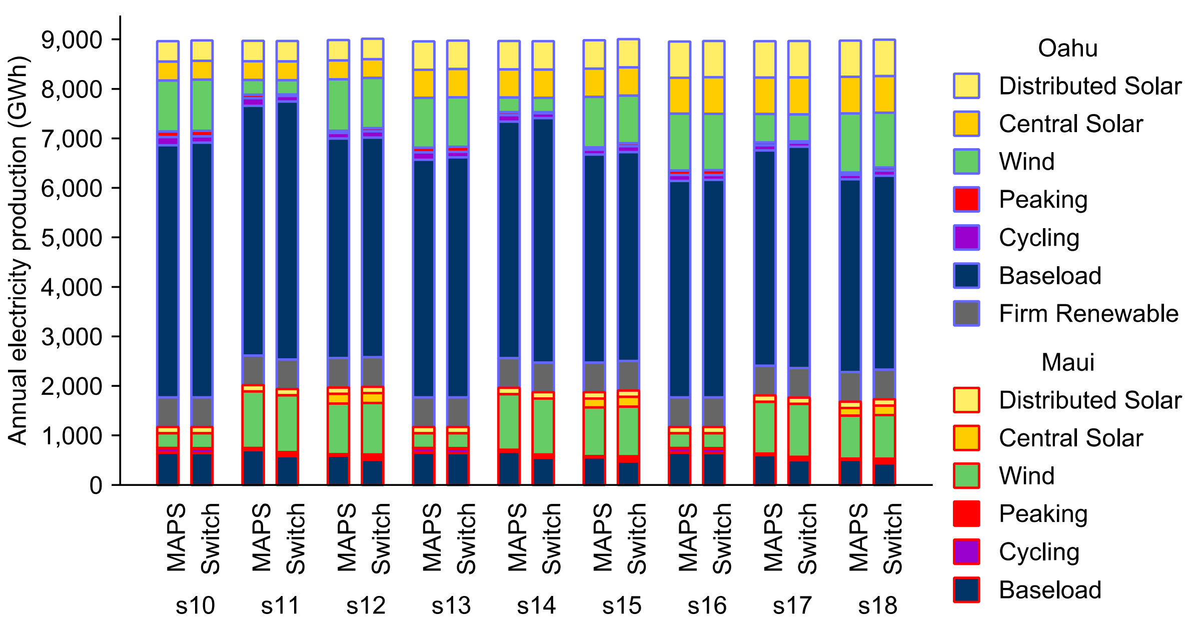

Figure 2. *Annual production from each source in scenarios 10–18, as calculated by GE MAPS and Switch (paired columns for each scenario). Upper, blue-bordered rectangles show Oahu generators; lower, red-bordered rectangles show Maui generators*

Table 3 shows R^2 values (squared correlation coefficients) between results from MAPS and Switch, for total production from each power source across all scenarios. The R^2 value is above

99% for all the renewable power sources, indicating that Switch and GE MAPS agree on more than 99% of the variation across scenarios. The R^2 value is 69–100% for the thermal power plants. The lower values for these plants appear to reflect small differences in prioritization of the various thermal plants relative to each other, as shown in Figures 1 and 2.

Table 3. *R^2 value (squared correlation coefficient) between total energy production in GE MAPS and Switch, across scenarios 2–17, for each power source and island*

	Island	
Power Source	**Oahu**	**Maui**
Distributed Solar	1.000	1.000
Central Solar	0.999	0.991
Wind	0.994	1.000
Peaking	0.747	0.668
Cycling	0.652	0.976
Baseload	0.993	0.766
Firm Renewable	1.000	N/A

It is difficult to explain or correct the differences between the two models using the details reported from the RPS Study. In Section 2 of this report we identified several areas where we made assumptions for Switch that may have differed from those used in GE MAPS; many of these could contribute to the observed differences in annual operation of the power system. These areas include: generator outages (section 2.3.6), calculation of down-reserve targets (section 2.8.2.1), commitment order for Oahu and Maui power plants (section 2.9.1), commitment rules (section 2.9.2), treatment of the inter-island cable during unit commitment and dispatch, operating rules for Maui's Maalaea combined-cycle plants (sections 2.3.2.4 and 2.3.3), and variable cost of the Kalaeloa plant (section 2.3.1). With a different focus, the RPS Study report does not fully document these assumptions for GE MAPS and does not include time-resolved outputs for most scenarios, so we were unable to determine how these factors (or others) contributed to these differences.

3.2 Annual Curtailment in Each Scenario

Figure 3 compares curtailment rates between the Switch and GE MAPS modeling. There is one colored marker for each scenario as modeled by Switch, and one black ring for the equivalent scenario in GE MAPS. The x values for each marker show the amount of wind and solar power that was potentially available in that scenario, found by summing the hourly potential reported by GE in ref. 34 (also see section 2.7 above). The y values show the percentage of renewable power that was left unused due to curtailment in each scenario. These calculations include wind, distributed solar and utility-scale solar. Figure 3 shows the same calculation as the RPS Study reported on the right side of its own Figure 4b [1, p. 18]; however, we have used "GWh available" as the x-value, while the RPS Study used "GWh produced".

The comparison in Figure 3 mostly follows from the results discussed in section 3.1. GE MAPS and Switch produce very similar results overall, with a median difference in curtailment of 0.13 percentage points and differences of less than 0.3 percentage points for all but three scenarios (5, 15 and 18). Overall, the R^2 between the two models is 0.973, indicating that Switch and GE MAPS agree on about 97% of the variation in curtailment between scenarios.

The biggest difference is in scenario 5, where Switch has 1.0% curtailment vs. 3.1% for MAPS. Scenario 5 is a relatively high wind scenario, and the difference is mainly due to curtailment of 41 GWh more of Oahu wind in Switch (about 0.5% of total power production, barely visible in Figure 1 in section 3.1).. Scenarios 15 and 18 have the highest levels of renewable deployment and include both gen-tie wind and an inter-island grid tie. In these scenarios, Switch's curtailment was 0.6–0.7 percentage points higher than GE MAPS.

We have not been able to identify the cause of the extra curtailment in Switch. Some possibilities include differences in the way that GE MAPS and Switch scheduled outages, allocated down reserves, or prioritized commitment of different thermal plants.

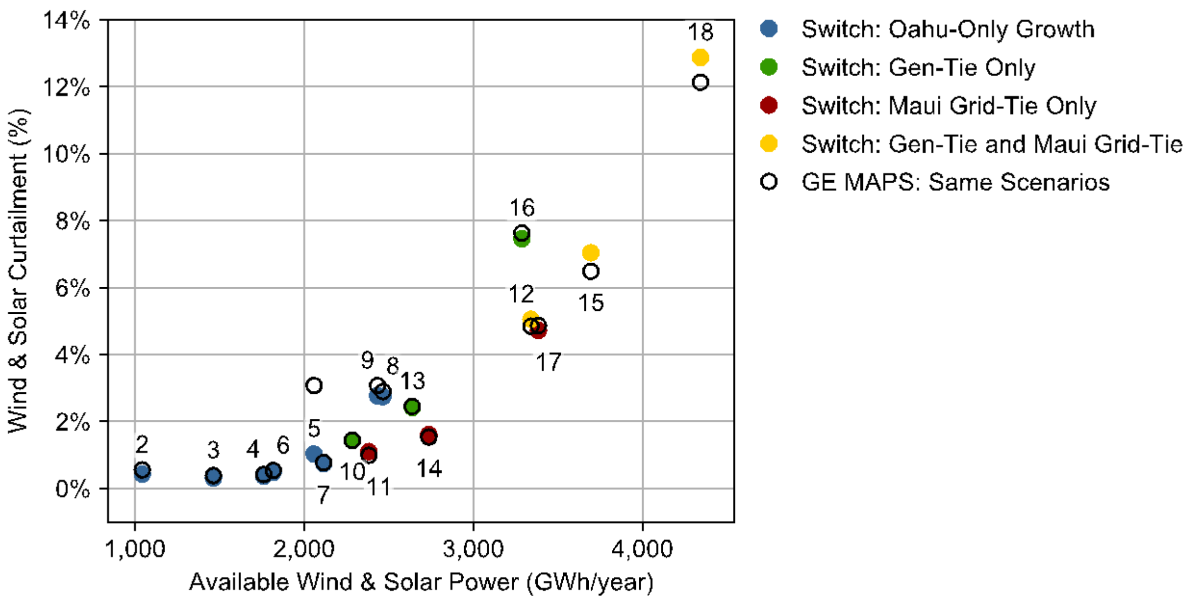

Figure 3. *Curtailment rate calculated by Switch and GE MAPS in scenarios 2–18*

3.3 Hourly System Operation

3.3.1 Scenario 2

Figure 4 shows hourly operation of the Oahu power system in scenario 2, as reported for GE MAPS (upper plot, reproduced from the RPS Study [1, p. 22]) and Switch (lower plot). This is for the week of June 22–28. The two models agree closely on the use of each type of plant. However, similar to the annual results, Switch uses less cycling generation (purple) and more baseload generation (blue/teal shades) than MAPS on the Saturday and Sunday. Specifically, Switch commits only one cycling plant from 11 am to 3:59 pm on the Saturday and 8 am to 3:59 pm on the Sunday, while MAPS commits two cycling plants during these times. In both cases the cycling plant(s) run at minimum load (22.5 MW each), and primarily provide reserves. Switch also decommits Kalaeloa 2 & 3 an hour earlier than MAPS on the Sunday evening.

We could not identify a reason for the discrepancies in the hourly profiles from the two models. It is possible they are caused by different treatments of minimum up-/down-times for power plants (on the Saturday, one cycling unit exactly meets both of these limits), or MAPS may have been configured to optimize commitment beyond the minimum needed for load and reserves (Switch was configured to commit only the minimum required capacity).

We also note that GE MAPS slightly reduces output from Kalaeloa 1&2 during the times of lowest power demand on Wednesday and Thursday nights, and this effect was slightly weaker in the Switch modeling. This suggests that GE MAPS may have used a higher minimum-load or down-reserve requirement for the Kahe and Waiau baseload units than Switch did. This is a reasonable possibility, given the uncertainty about how GE MAPS allocated the down reserve target among plants, discussed in section 2.8.2.2.

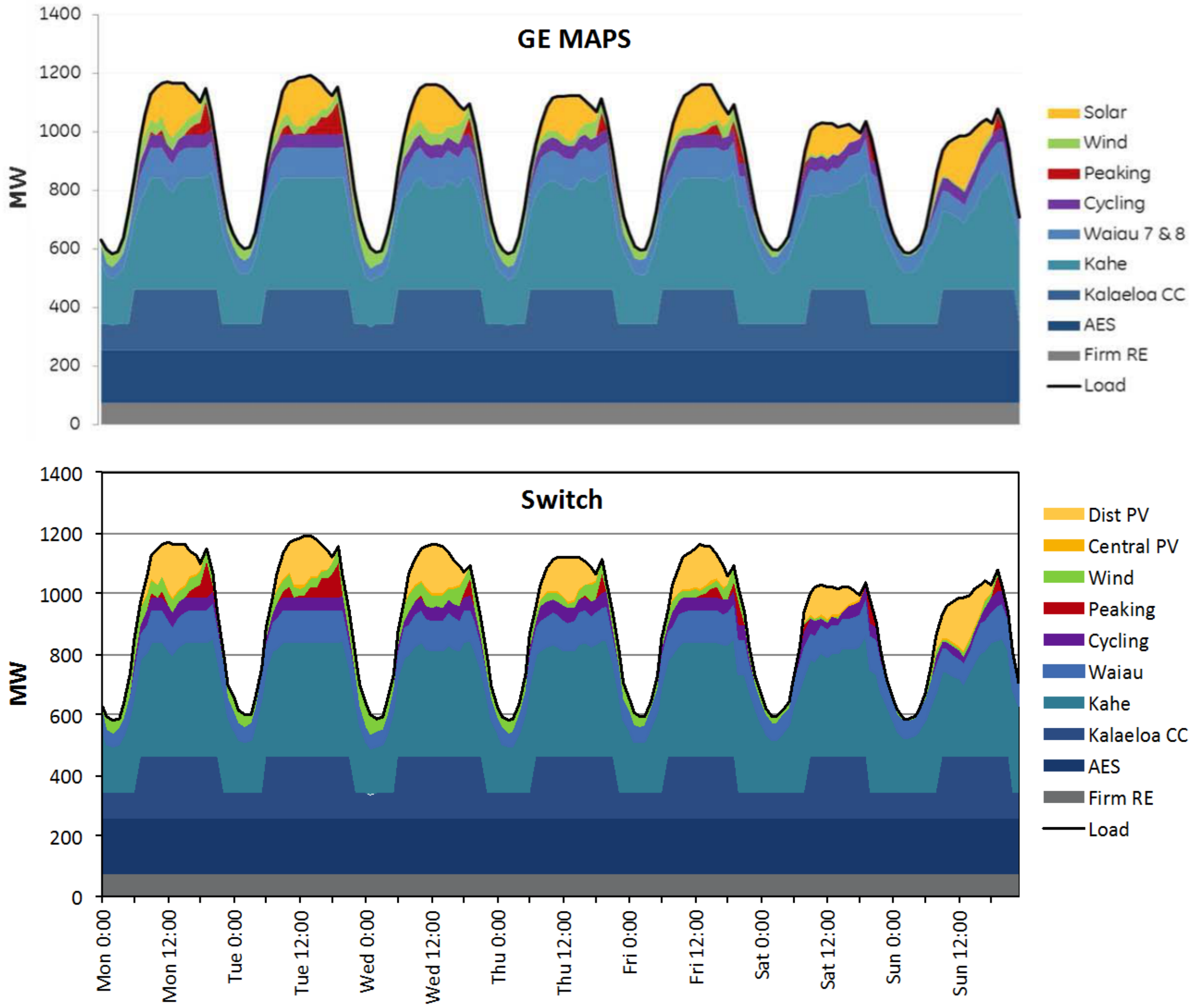

Figure 4. Hourly power production in Scenario 2 during the week of June 22–28, calculated by GE MAPS and Switch

3.3.2 Scenario 16

Figure 6 compares hourly results for scenario 16 between GE MAPS and Switch (with the standard assumptions used for the rest of this comparison). Again the match is excellent overall, but Switch used slightly more baseload generation and less cycling generation than was shown for GE MAPS. For example, Switch decommits Kalaeloa 2 & 3 at midday on Tuesday, late morning on Wednesday and late evening on Sunday, while MAPS keeps them running. Switch also runs less cycling capacity (purple) than MAPS on Monday afternoon, Friday afternoon and at 6 pm on Saturday.

As with scenario 2, we couldn't identify a definite cause for these differences; likely possibilities include differences in the rules that were used to enforce minimum up/down time and the freedom the models were given to optimize commitment beyond the minimum requirements.

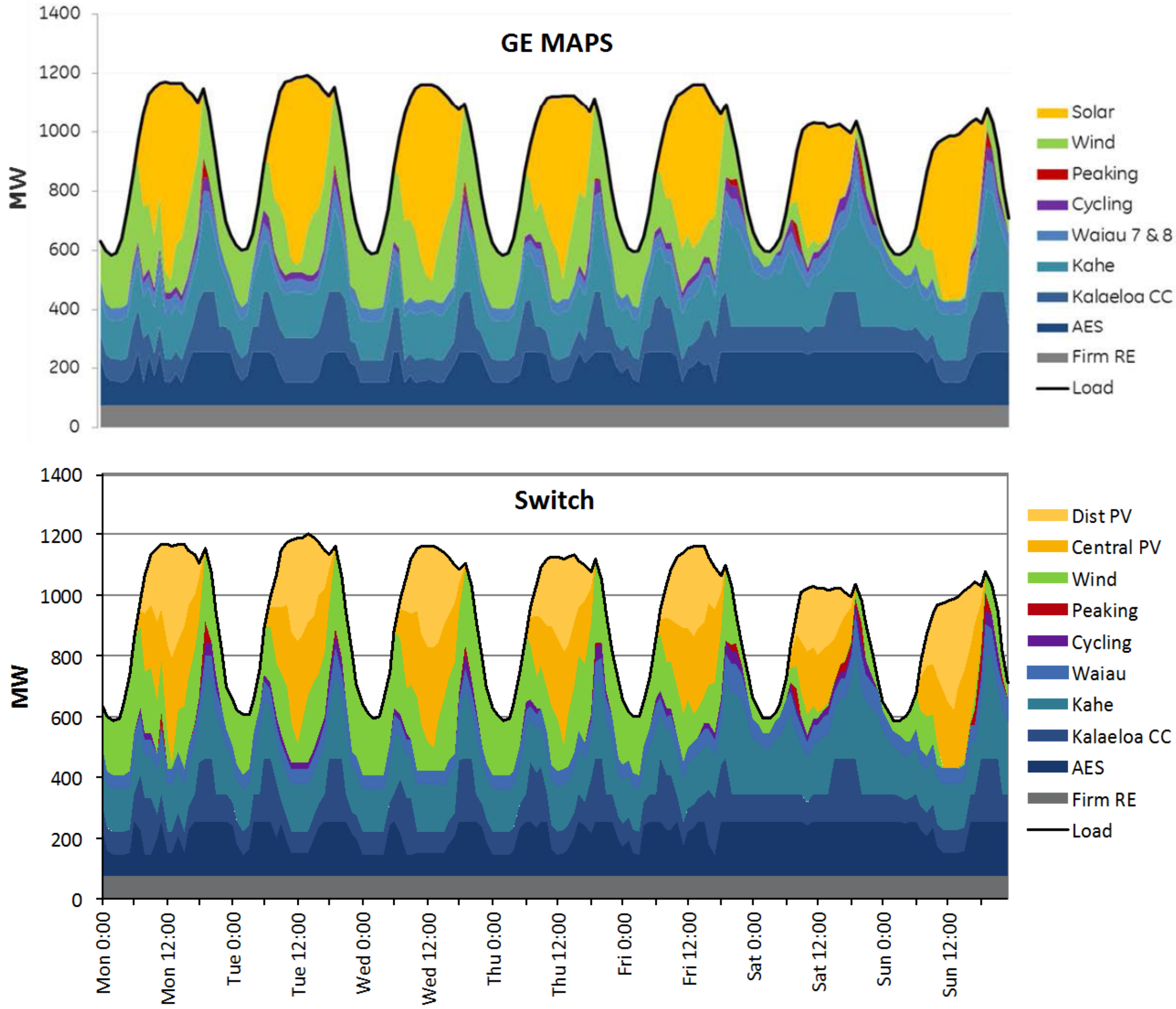

Figure 5. *Hourly power production in Scenario 16 during the week of June 22–28, calculated by GE MAPS and Switch with standard model settings*

4 CONCLUSION

The GE MAPS production cost model is widely used for renewable energy integration studies, including the recent *Hawaii Renewable Portfolio Standards Study* (RPS Study). The goal of this intermodel comparison was to test whether similar results could be obtained from the newer Switch model when studying a high-renewable power system for Hawaii. We invested significant effort to identify the assumptions and rules that were input to GE MAPS for the RPS Study, but some uncertainty remains about these inputs. However, we found that despite this uncertainty, once we configured Switch similarly to GE MAPS, it produced results that were very close to GE MAPS for these small, island power grids. This work gives us confidence to move ahead using Switch to study the interaction between EV charging and high-renewable power systems in Hawaii, and the opportunities for synergies between well-timed charging of EVs and operation of high-renewable power systems. Those findings will be presented in additional reports, building on other reports from the project on the “Effect of Electric Vehicles on Power System Expansion and Operation” of the Electric Vehicle Transportation Center (EVTC) [43, 44].

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